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OTC 4353

An Experimental Study of Well Control Procedures for Deep Water Drilling Operations

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ABSTRACT

As the search for petroleum reserves has moved into the deep water offshore environment, the blowout control problem has continued to increase in complexity. Several special well control problems for floating drilling operations stem from the need for long subsea choke lines connecting the subsea blowout preventer stack at the sea-floor to the surface well-control system. The magnitude of these problems are made worse by the very low effective formation fracture gradients generally associated with drilling operations in deep water.

A research facility has been designed and constructed to model the well-control flow geometry present on a floating drilling vessel operating in 3000 feet of water. The main features of this facility are: (1) a highly instrumented 6000 ft well equipped with a packer and triple parallel flow tube at 3000 feet to model a subsea BOP stack with connecting subsea choke and kill lines, (2) a choke manifold containing several 15,000 psi adjustable drilling chokes of varying design features, (3) a conventional mud circulating system powered by a triplex pump, and (4) an instrumentation and control house.

Flow tests were conducted for several drilling chokes and the behavior of each choke was described using a frictional area coefficient correlation. Several types of experiments were conducted in which gas kicks were simulated by the injection of nitrogen into the bottom of the well. Alternative procedures studied and evaluated included techniques for compensating for choke-line frictional pressure loss during pump start-up and techniques for handling rapid gas zone elongation when the kick reaches the sea floor. The results obtained differ significantly from those predicted by computer simulation of the test conditions studied. It was found that the demands placed upon a choke operator during well control operations in deep water were not as severe as anticipated from computer simulation studies and could be managed with existing equipment by an experienced choke operator.

References and illustrations at end of paper.

INTRODUCTION

In the late 1940's, the search for oil and gas accumulations first moved offshore to the shallow marine environment. Since that time, drilling operations have been extended steadily across the continental shelf. More recently, developments in the technology for drilling from floating drilling vessels have allowed exploratory drilling beyond the limits of the continental shelf and into the relatively deep water of the continental slopes. In 1974, the first well was drilled in a water depth in excess of 2000 feet.[1] Figure 1 shows how rapidly drilling operations have progressed into deeper water depths. In 1979, a well was drilled offshore from Newfoundland in a water depth of 4876 feet.[2] Future plans in the Ocean Margin Drilling Program of the National Science Foundation call for scientific ocean drilling during the next decade in water depths of 13,000 feet.[3]

As the search for oil and gas is extended to greater water depths, the number of wells drilled each year in deep water is also increasing. Figure 2 shows the number of wells drilled each year in water depths in excess of 2000 feet. In 1980 alone, nineteen wells were drilled. At least in a global sense, deep water drilling operations are becoming routine.

Like many other aspects of drilling operations, the problem of blowout prevention increases in complexity for floating drilling vessels operating in deep water. Several special well control problems stem from a greatly reduced fracture resistance of the marine sediments and from the use of long subsea flow lines extending vertically from the blowout preventer (BOP) stack at the sea floor to the choke manifold and other well-control equipment located at the surface. Shown in Figure 3 is the approximate effect of water depth on fracture resistance, expressed in terms of the maximum mud density which can be sustained during normal drilling operations without hydrofracture. Note that the maximum mud density which can be used with casing penetrating 3500 feet into the sediments decreases from about 13.9 ppg on land to about 10.7 ppg in 1500 feet of water, and to about 9.8 ppg in 13,000 feet of water. The lower fracture resistance results primarily because the drilling fluid column which must be supported extends far above the mudline to the rig floor which is significantly above sea level and because the drilling fluid density exceeds sea water density. An additional factor often contributing to the reduced fracture resistance is a relatively low bulk density of unconsolidated shallow marine sediments.

The required vertical subsea choke lines between the BOP stack at the sea floor and the surface well-control equipment have two detrimental aspects. One difficulty arises because of the increased circulating frictional pressure loss caused by the long length of flow line. This choke line frictional pressure loss can cause a significant increase in the pressures occuring in the well bore. The combination of high circulating pressure losses in the choke line and low well-bore fracture resistance reduces the tolerance for error by the choke operator.

A second difficulty arises due to rapid changes in hydrostatic pressure in the vertical subsea flow lines when low density formation fluids are circulated through these lines. In the case of a gas kick, hydrostatic pressure falls quickly as the gas exits the large casing and proceeds upward through the relatively small diameter choke line. In order to maintain the bottom hole pressure constant, there must be a corresponding increase in surface choke pressure to make up for this decrease in hydrostatic pressure. Choke operation becomes much more difficult during this period, as rapid changes in control pressure are required. This difficulty tends to increase with well depth because choke manipulation is based on surface drill-pipe pressure whose unsteady-state readjustment time increases with well depth.

Evaluations of anticipated well control problems for a given set of field conditions are often conducted, at least in part, by computer studies which predict the pressure response of a well for various alternative procedures being evaluated. Unfortunately, realistic computer simulations of well control operations require both an accurate knowledge of fluid behavior in the well and a knowledge of equipment response. Considerable difficulty is encountered in accurately modeling the flow behavior of mixtures of formation gas and drilling fluids in the complex flow geometry present in the subsea system.

For this study, a research well facility was designed and constructed to model the flow geometry present on a floating drilling vessel during well control operations. Several types of experiments have been conducted in which gas kicks were simulated by the injection of nitrogen gas into the bottom of the well. Alternative procedures studied included techniques for compensation of choke-line frictional pressure loss during pump start-up and techniques for handling rapid gas zone elongation when the kick reaches the sea floor.

EXPERIMENTAL WELL FACILITY

Design of the first subsea well-equivalent to be located on dry land posed many problems. The first step was a review of all drilling vessels which have operated in deep water. It was found that from 1974 through 1980 only 66 wells had been drilled in water depths in excess of 2000 feet. These wells were drilled by the twelve vessels listed in Table 1. Thirty-five of these wells were drilled by only three vessels, all of which are dynamically positioned. One of these, the Discoverer Seven Seas, has held the water depth record for offshore drilling since 1976. A survey of the well-control equipment on 10 of the vessels previously listed showed similar design features and pressure ratings. All had BOP equipment with 10,000 psi pressure ratings and two subsea lines. The inside diameter of the choke and kill lines ranged from 2.4 to 3.5 inches, with 3-in. or larger lines being used on six of the vessels.

In the absence of any detailed records, computer simulations were used to predict the dynamic behavior of a deep-water well during the pump-out of a kick. Actual well data together with proposed drilling programs[3] were modeled to determine those parameters most significant to the successful control of a well kick. Shown in Figure 4 is a schematic drawing of a well drilled in 1978 in 4342 feet of water off the Congo with the drill-ship Discoverer Seven Seas. This well was drilled to a depth of over 16,000 ft with no reported drilling kicks. The situation shown in the figure, however, represents expected shut-in conditions resulting from a 0.5 ppg kick while drilling with a 9.2 ppg mud at a depth of 11,540 feet. The complete mud program for the well was obtained from the operators along with most of the supporting data given in Table 2.

A graphic history of predicted well behavior during pump-out of the kick is shown in Figure 5. Before analyzing these results, it would be well to review the following questionable assumptions inherent to the model which generated this data:

1. Formation gas enters the well as a continuous slug and retains this configuration as it moves up the annulus and into the choke line.

2. The slip velocity of the gas relative to the mud is zero.

3. The choke operator maintains the bottom hole pressure constant at exactly the desired value.

While these assumptions might introduce some inaccuracies in the computed results, the results were felt to be sufficiently valid to be used in design considerations of the experimental facility.

Consideration of Figure 5 shows several important aspects of the well-control process which the experimental facility must model. An initial shut-in choke pressure of 440 psig results in a well-bore pressure at the casing seat very near the fracture pressure. The circulating frictional pressure loss in the choke line is 280 psi for a pump speed of 50 spm and, upon pump start-up, the choke pressure falls from 440 psig to 160 psig. There follows a long and relatively uneventful period as the kick is circulated from the bottom of the well to the seafloor. However, once the gas reaches the seafloor and enters the choke line, the choke pressure must rapidly increase from less than 100 psig to more than 2100 psig. A short time later, a rapid decrease in choke pressure is required as mud displaces gas from the choke line. The average mud velocity in the choke line, which is felt to be a measure of how rapidly the pressures must change, is 562 ft/min in this example.

Numerous examples, such as the one shown in Figure 5, were studied using data from different rigs and a wide variety of assumed well conditions. Other examples were studied using data from proposed wells in the Ocean Margin Drilling Program[3] which have been planned for water depths of up to 13,000 feet. Computed choke-pressure profiles are shown in Figure 6 for the proposed modified Glomar Explorer drillship on a location offshore from New Jersey in 7875 ft of water. Note that the results are similar to those previously discussed.

In addition to reviewing the well-control equipment of vessels which have operated in deep water, a review of available literature was made to identify special well-control procedures that have been proposed to solve the blowout prevention problems which are unique to the deep water environment. A list of 42 training schools which have been approved by the Minerals Management Service (formerly the Conservation Division of the U.S. Geological Survey) for well control training related to subsea BOP Stacks was obtained. Training manuals from many of these schools were received and reviewed. From the literature review it was determined that many of the special well-control procedures proposed for floating drilling vessels require the use of two subsea flow lines.

It was felt that the experimental well facility should model the significant phases of the previously discussed example and allow the experimental study of the special well-control procedures identified. The desired features of the experimental well facility included:

1. realistic values for circulating frictional pressure loss in the choke line.
2. realistic values for changes in choke pressure when a gas kick is circulated through the choke line.
3. realistic values of circulating drill pipe pressures.
4. the availability of two subsea flow lines, one of which could be closed at the simulated sea floor to prevent collection of gas in the line when it was not in use.
5. reasonable kick simulation time.
6. reasonable initial cost and operating cost.
7. reasonable nitrogen injection pressure at realistic gas influx rates.

All of these factors interact considerably, making an optimal design difficult to determine.

The final well design selected is shown in Figure 7. A simulated water depth of 3000 feet was selected and the simulated subsea choke and kill lines (2.375-in. tubing) were run inside 10.75-in. casing to this depth. The effect of the BOP stack located on the sea floor is modeled in the well using a packer and triple parallel flow tube designed by Baker. A subsea kill line valve at 3000 feet is modeled by using a surface-controlled subsurface safety valve. This control allows experiments to be conducted using only the choke line, the kill line being isolated from the system as is often the case in well-control operations on floating drilling vessels. The drill string is simulated using 6000 feet of 2.875-in. tubing. Nitrogen gas is injected into the bottom of the well at 6,100 feet through 1.315-in. tubing placed in the drill string. A pressure sensor is located at the bottom of the nitrogen injection line to allow continuous surface monitoring of bottom hole pressure during simulated well-control operations. The pressure signal is transmitted to the surface through 0.125-in. capillary tubing which is strapped to the 1.315-in. tubing. A check value, located at the bottom of the nitrogen injection line, allows the line to be isolated from the system after inducing the gas kick in the well.

A graphic history of predicted experimental well behavior during pump-out of a typical kick is shown in Figure 8. At a circulating rate of 2 bbl/min, a choke line friction of 340 psi was predicted. When the gas reached the seafloor, the choke pressure must increase rapidly from about 200 psig to about 1700 psig. A short time later, a rapid decline in choke pressure is required. The average velocity of mud in the choke line is 517 ft/min. Pumping time for a complete kick simulation is about one-hour and circulating drill pipe pressure is about 1700 psig. Realistic kick simulations can be accomplished with reasonable gas volumes and pump horsepower requirements.

A schematic of the associated surface equipment for the experimental well facility is shown in Figure 9. The main components of this equipment include: (1) a choke manifold containing several 15,000 psi adjustable drilling chokes of varying design, (2) a 250 hp triplex mud pump, (3) two mud tanks having a total capacity of 540 bbl, (4) two 15 bbl metering tanks, (5) a mud gas separator, (6) three mud degassers of varying designs, (7) a mud mixing system, and (8) an instrumentation and control house. A photograph of the new facility, which is on the LSU Campus, is shown in Figure 10. A photograph taken inside the instrumentation and control house is shown in Figure 11.

RESULTS

Several types of experiments were conducted to study and evaluate a number of alternative procedures that have been proposed for well-control operations conducted on floating vessels in deep water. This work included the following areas:

1. Drilling-Choke flow characteristics.
2. Measurement of choke-line friction.
3. Pump start-up procedures.
4. Procedures for handling rapid gas zone elongation in subsea choke lines.

Drilling-Choke Flow Characteristics

One approach often used to gain insight into the demands being placed on the choke operator for a given set of kick conditions is to estimate the changes in choke pressure which must be accomplished during well control operations to maintain the bottom hole pressure constant and slightly above the formation pressure. Previously discussed examples of computed choke pressure profiles are shown in Figures 5, 6, and 8. In order to translate this information into required changes in choke position, the flow characteristics of the commercially available drilling chokes must be known. Flow tests were conducted for two drilling chokes and several drilling fluids in which the pressure drop across the choke for a given choke position and flow rate was determined. Using these test results, the behavior of each choke was described using a frictional area term as recommended by Pool.[5]

The pressure drop across a choke through which is flowing a slightly compressible fluid can be approximately represented in any consistent english or metric units by

$$\Delta p = \frac{\rho q^2}{2\, g_c} \frac{1}{A_f^{\,2}} \quad \text{. . . . . (1a)}$$

where A_f is the effective frictional area of the choke for a given choke adjustment. The frictional area, A_f, must be determined experimentally. One set of commonly used units are psi for pressure, lb/gal for density, gal/min for flow rate and sq-in. for area. For this set of units, Equation (1a) becomes

$$\Delta p = \frac{\rho q^2}{12032} \frac{1}{A_f^{\,2}} \quad \text{. . . . . (1b)}$$

Unfortunately, there are other commonly used expressions for describing flow through a choke. These alternative equations involve the use of either a valve coefficient, C_v, or the use of an actual choke port area, A_o, corrected by an appropriate discharge coefficient, C_d. The effective frictional area is related to these other parameters as follows:

$$A_f = \frac{C_v}{38} \quad \text{. . . . . (2)}$$

$$A_f = \frac{C_d^{\,2}\, A_o^{\,2}}{\left[1 - \left(\frac{A_o}{A_1}\right)^2\right]} \quad \text{. . . . . (3)}$$

These expressions allow the results obtained in this study to be easily converted to the other commonly used terms.

Experimental results for two commercially available drilling chokes are shown in Figures 12-13. In addition to conducting tests with water, three unweighted clay-water muds of varying viscosities, and two weighted clay-water muds were used. During the tests, choke position was measured mechanically at the choke and then converted to a fraction of full open as approximately shown by the choke position indicator in the remote control panel. The results indicated that the frictional area coefficient for a drilling choke was relatively insensitive to mud viscosity over the usual range of field conditions. A single frictional area curve was felt to be sufficient for computer simulation studies of well-control operations. As the choke elements wear, a shift to the left in the curve would be expected.

It was also noted that for the flow rate ranges commonly used in well control operations, only a very small portion of the total choke adjustment range is used. A large maximum choke opening is desirable due to concern about the ability to unplug a choke which has become blocked by cuttings in the mud. However, relatively small choke openings are required to impose a significant pressure on the well.

Choke-Line Friction

The circulating frictional pressure loss in the choke line must be accurately known in order to minimize the risk of hydrofracture during well-control operations. Several techniques that have been proposed for routine measurement of this parameter are shown in Figure 14. The first method involves taking the difference between the drill pipe pressure required to circulate the well through the choke line with the BOP closed and the drill pipe pressure required to circulate the well through the marine riser with the BOP open. Care must be taken to insure that the same pump rate is used in both measurements and that the mud properties in the well are not changing significantly between measurements. Ilfrey, et al[6] recommends adjusting the choke when using this technique until a mid-range choke pressure is also observed while flowing through the choke line. In this case, the circulating frictional pressure loss in the choke line is the drill pipe pressure observed when circulating through the choke line minus choke pressure minus the drill pipe pressure observed when circulating through the marine riser.

The second technique shown in Figure 14 involves circulating the well through the choke line with the BOP closed and noting the pressure observed on a static kill line. If care is taken to insure that the same fluid is in both the choke line and the kill line, the kill line pressure will be equal to the circulating frictional pressure loss in the choke line at the given pump speed. Again, Ilfrey et al[6] recommends adjusting the choke so that a mid-range choke pressure is observed. If this is done, the circulating frictional pressure loss in the choke line is equal to the kill line pressure minus the choke pressure.

The third technique illustrated in Figure 14 involves pumping down the choke line and up the marine riser with the BOP open. In this case, the pump pressure required for circulation, which is equal to the surface pressure on the choke line, is also equal to the circulating frictional pressure loss in the choke line.

A distinct disadvantage of the first two techniques is that while measuring the choke line friction, the well bore is subjected to a total pressure in excess of that imposed while drilling. The excess pressure is the frictional pressure loss in the choke line. The third technique has the advantage of not placing any additional back-pressure on the well. Thus, choke line friction can be measured without any fear of hydrofracture in the uncased portion of the well bore. As a consequence, more frequent measurements of friction could be made, say, twice a day. Then upon taking a kick, the most recent measurement of choke line friction would be more representative of the flow behavior of the mud currently in the well.

Circulating frictional pressure losses measured in the choke line of the experimental well are shown in Figure 15 for one mud. Pressures were measured using a 0-5000 psi Bourns model 520 transducer. The mud properties were measured in a standard rotational viscometer at 600 and 300 rpm, with samples taken from the return flow line at the surface. The solid line indicates values computed using the Fanning equation, the Colebrook function with absolute pipe roughness, ε, of 0.00095 in. and the use of plastic viscosity in the calculation of Reynolds numbers. For any consistent set of metric or english units, these equations are given by:

$$\Delta p_f = \left(\frac{fL}{d}\right) \frac{2\rho\bar{v}^2}{g_c} \quad \ldots\ldots\ldots\ldots\ldots (4)$$

where

$$\frac{1}{\sqrt{f}} = -4 \log\left(\frac{\varepsilon}{3.72d} + \frac{1.255}{N_R \sqrt{f}} \right) \quad \ldots\ldots (5)$$

$$N_R = \frac{d\bar{v}\rho}{\mu_p} \quad \ldots\ldots\ldots\ldots\ldots\ldots (6)$$

Note that there is good agreement between the measured and computed values.

Pump Start-Up Procedures

Conventional well control procedures assume that frictional pressure losses held against the well are small and can be applied as a convenient safety margin when circulation of the kick is initiated. Thus the choke operator can simply adjust the choke to maintain the choke pressure constant as the pump speed is advanced to the desired value. After constant pump speed is established, the choke operator can then use the drill pipe pressure as the control parameter.

Use of the conventional pump start-up procedure on a floating vessel in deep water is thought to greatly increase the risk of hydrofracture. The circulating frictional pressure loss in the choke line is often too large to be safely applied as additional back-pressure on the well. Alternative procedures that have been suggested for the case of a floating vessel in deep water include the use of (1) a computed choke pressure schedule, (2) a casing pressure monitor, and (3) multiple choke lines. The first two alternatives, as illustrated in Figure 16, attempt to keep the pressure on the subsea wellhead constant by dropping the choke pressure by an amount equal to the frictional loss in the choke line at the given intermediate pump rate. In the first case, the choke operator accomplishes this by adjusting the choke so that the choke pressure will follow the computed pressure schedule. In the second case, the choke operator adjusts the choke to maintain the static kill line pressure constant. Both of these techniques are completely applicable only for pump rates at which the circulating frictional pressure loss in the choke line is less than the shut-in choke pressure. If the choke and kill lines contain a fluid of different density than the current drilling mud, then application of the first technique is not practical, but the second technique can still be applied.

The third alternative procedure is based on greatly reducing the frictional pressure loss held against the well through use of multiple choke lines. For example, by taking half of the mud returns through each of two choke lines, the frictional pressure would be reduced to about one-fourth of the value observed using a single line. In most cases, the reduction is sufficient to allow the conventional constant-choke-pressure pump start-up procedure to be safely employed. A disadvantage of using this approach is that a redundant system is no longer on stand-by in the event the choke lines become plugged.

Simulated well control exercises conducted to date indicate that all of the alternative pump start-up procedures are feasible. However, they all require considerable practice to master with a high degree of accuracy. Shown in Figure 17 are typical results obtained during training exercises. Pressure variations of the order of 150 psi above or below the target pressure are common.

Rapid Gas-Zone Elongation

Computer simulations of well-control operations for floating drilling vessels in deep water, such as the example shown in Figure 5, have indicated that very rapid changes in choke pressure are required when the gas reaches and exits the BOP stack at the seafloor. A major question to which this study was directed is whether a choke operator can react in step with rapidly changing conditions. Suggested solutions to this anticipated problem include:

1. Use of greatly reduced pump rates, perhaps just before the gas reaches the seafloor.

2. Use of multiple choke lines.

3. Use of larger diameter choke lines.

All of these suggested solutions attempt to give the choke operator additional reaction time by slowing the average upward fluid velocity in the choke line.

Simulated well control exercises conducted in the experimental well have indicated that the demands placed on the choke operator are not as severe as previously anticipated. What is observed when the gas kick reaches the sea floor and begins entering the choke line is a natural tendency for the casing pressure to increase with time. Although some choke adjustments are required to maintain the desired drill pipe pressure, they are much less severe and frequent than expected and can be handled by an experienced operator. Shown in Figure 18 are the results of a simulated well-control exercise in which a 20 bbl gas kick was pumped out at a kill speed of 2.5 bbl/min using a single choke line. In this example the choke was operated by Mr. John Johnson of Tenneco Oil Co. and the pump was operated by Mr. Robert Duhon of Chevron, USA. The exercise was handled with minor difficulties encountered when the trailing edge of the gas zone was displaced up the choke line. The choke adjustment was varied in this exercise between a maximum setting of 0.25 and a minimum setting of 0.10.

Some theoretical considerations are shown in Figure 19 as to why the choke pressure has a natural tendency in the desired direction when the gas reaches the sea floor. Calculations show that as the leading edge of the gas contaminated region begins moving up the choke line, the gas pressure begins to fall at an accelerated rate, causing the gas to expand at an accelerated rate. The flow rate of the mud exiting the well through the choke increases in response to this gas expansion, resulting in an increase in choke pressure. In addition, the choke data given in Figures 12-13 indicate that large pressure increases can be accomplished with relatively small adjustments in choke position.

Although the problems encountered when a gas kick reaches the seafloor appear to be less severe than originally anticipated, they should not be taken too lightly. For many individuals, considerable practice is required to maintain the bottom hole pressure constant during the period that gas is being produced. Maximum difficulty tends to occur when the trailing edge of the gas region is being displaced up the choke line. Shown in Figure 20 are the results of a well control exercise conducted with a less experienced choke operator.

The results of conventional computer simulations of expected choke pressures for a perfect choke operator are also shown in Figures 18 and 20 for comparison to the observed behavior. Recall that the computer model ignores the effect of upward gas slippage with respect to the mud and the effect of gas-mud mixing. Note that the effect of gas slippage is quite pronounced, as gas reached the seafloor much sooner than predicted. The effect of gas-mud mixing is also significant, as observed peak pressures are lower than predicted because the displacement of mud from the choke line is not complete. Peak pressures observed were found to be strongly influenced by the gas influx rate at the time the kick is taken.

CONCLUSIONS

1. An experimental well facility has been used successfully to model the well-control flow geometry present on a floating drilling vessel operating in 3000 feet of water.

2. The model provides realistic conditions with respect to circulating frictional pressure losses in the choke line and with respect to rapid changes in choke pressure when a gas kick is circulated through the choke line.

3. The model is reasonably economical to operate, requiring relatively small gas volumes, pump horsepower, and circulating times to complete a kick simulation.

4. Flow of mud through several commerically available drilling chokes can be modeled using frictional area coefficient correlations.

5. Frictional area coefficients for drilling chokes are only slightly influenced by mud viscosity for the range of viscosities commonly used in field practice.

6. Frictional pressure losses in choke lines for unweighted clay-water muds were accurately predicted by flow equations based on a Bingham Plastic Model.

7. Several alternative procedures can be successfully used to cancel the detrimental effect of choke-line frictional pressure losses during pump start-up. However, all of these procedures require considerable practice to master.

8. Choke pressure profiles observed in the experimental well differed significantly from those predicted by conventional computer simulations of well control operations in deep water. The maximum choke pressures observed were less than predicted and occurred much sooner than expected.

9. The demands placed on a choke operator when gas is circulated through a subsea choke line in deep water were not as great as predicted by computer simulations of well-control operations.

10. Well-control operations on floating vessels in deep water can be safely managed with existing equipment. However, proper choice of choke line diameter for the water depth range of the vessel is of critical importance. In addition, considerable hands-on practice may be required for the operator to master the needed special procedures.

NOMENCLATURE

A_1 - area of flow conduit upstream of choke orifice

A_o - area of choke orifice

A_f - frictional area coefficient of choke

C_d - discharge coefficient of choke

C_v - valve coefficient for choke which is defined as the gallons per minute of water flowing through the choke at 60°F for a one psi pressure differential across the choke

d - internal diameter of pipe

f - Fanning friction factor

g_c - units conversion constant

L - length

N_R - Reynolds number

p - pressure

Δp_f - frictional pressure loss

q - flow rate

$\bar{v}$ - average velocity

ε - absolute roughness

μ_p - plastic viscosity

τ_y - yield point

ρ - density

ACKNOWLEDGMENTS

Construction of the experimental well facility was accomplished only with the help of individuals and organizations too numerous to mention. Thirteen major oil companies gave grants totaling $200,000 in support of this work. Over 42 other companies provided services and equipment valued in excess of 1.2 million dollars. The facility also could not have been completed without the dedication of Jim Sykora, the coordinator of the project. Special thanks are also due Dan Bangert of Baker Packers and Bill Turnbull of Halliburton for extraordinary work on our behalf.

The research work was supported in part by the U.S. Geological Survey, Department of the Interior, under USGS Contract No. 14-08-0001-17225. However, the views and conclusions contained in this document are those of the authors and should not be interpreted as necessarily representing the official policies, either express or implied, of the U.S. government.

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Table 1 - Drilling Vessels Known To Have Operated In Water Depths In Excess of 2000 Feet

Rig Name	Number of Wells Drilled	BOP Stack Size (in.)	BOP Stack Working Pressure (psi)	Subsea Flowlines No.	Subsea Flowlines I.D. (in.)
Sedco 472	14	16.75	10,000	2	3.0
Discoverer Seven Seas	13	16.75	10,000	2	3.152
Sedco 445	8	16.75	10,000	2	3.0
Discoverer 534	7	16.75	10,000	2	2.728
Ben Ocean Lancer	5	16.75	10,000	2	3.5
Pelerin*	5	16.75	10,000	-	-
Sedco/BP 471	4	16.75	10,000	2	3.0
Penrod 74	4	18.75	10,000	2	2.5
Sedco 709	3	16.75	10,000	2	3.0
Pacnorse*	1	-	-	-	-
Zapata Concord	1	18.75	10,000	2	2.4
Petrel*	1	-	-	-	-
	66				

* Foreign Owned Vessel

Table 2 - Data for Congo Well Example.

WELL DATA

1. Casing: 13 3/8 in., J-55, 61 lb/ft
2. Drill Pipe: 5 in., 19.5 lb/ft
3. Drill Collars: 540 ft, 8 x 3 in.
4. Drill Bit: 12 1/4 in., 12-13-13/32 in. jets
5. Mud: 9.2 ppg, μ_p = 16 cp, τ_y = 10 lb/100 sq ft

PUMP DATA

1. Type: Single Acting Triplex
2. Liner Size: 6 1/2 in.
3. Stroke: 11 in.
4. Efficiency: 96 %

CIRCULATION DATA

Conditions	SPM	DP Pressures, psig Thru Riser	DP Pressures, psig Thru Choke Line	Choke Line Friction, psi
Norm. Drilling	110	2400		
Reduced Rate 1	50	600	880	280

KICK DATA (Simulated)

1. Shut-in DP Press.: 300 psig
2. Shut-in Choke Press.: 440 psig
3. Pit Volume Gain: 30 bbl

Annual Water Depth Record

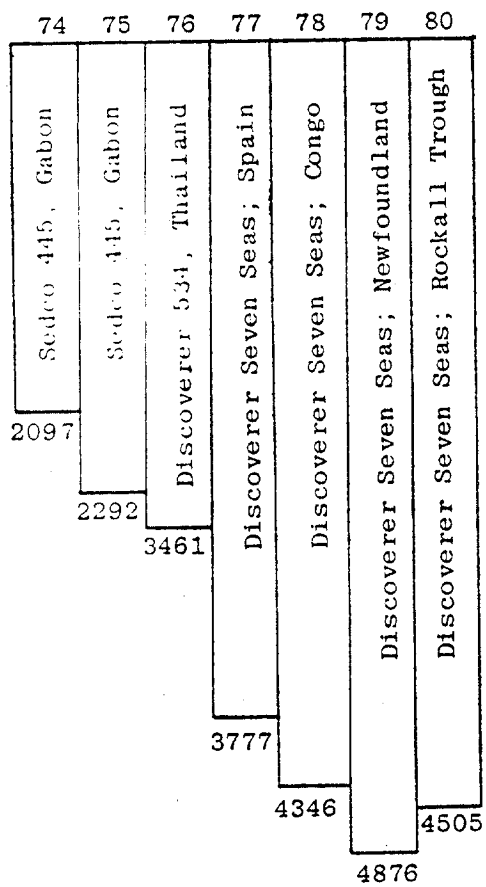


Figure 1 - Annual Water Depth Record for Drilling Operations with Marine Riser, 1974-80 [4]

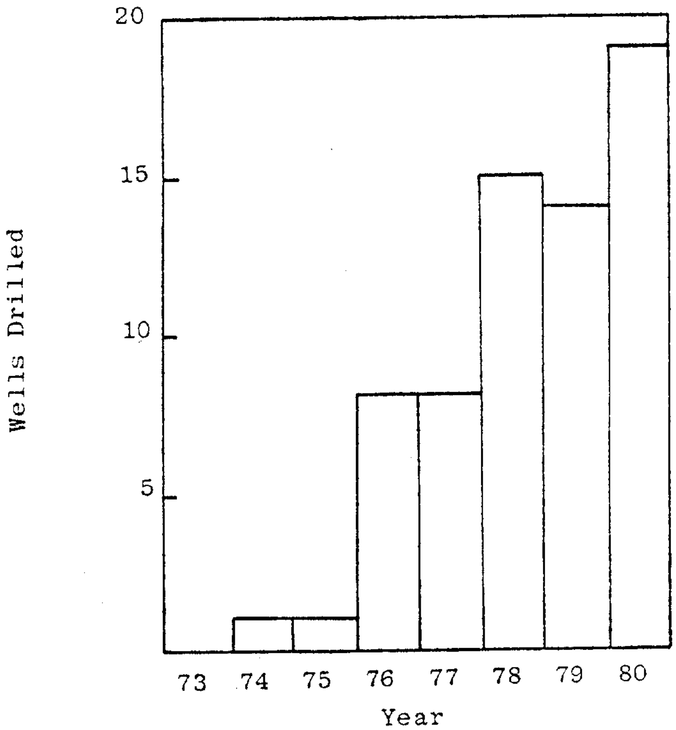


Figure 2 - Annual Number of Wells Drilled in Over 2000 feet of Water[4]

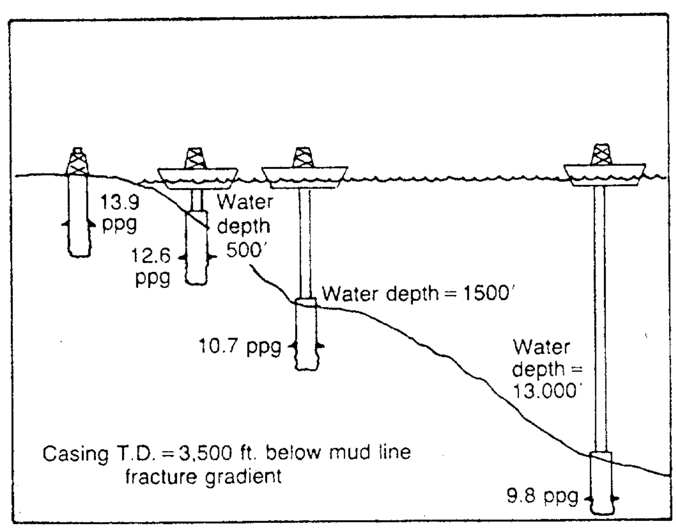


Figure 3 - Approximate Effect of Water Depth on Fracture Gradient[3]

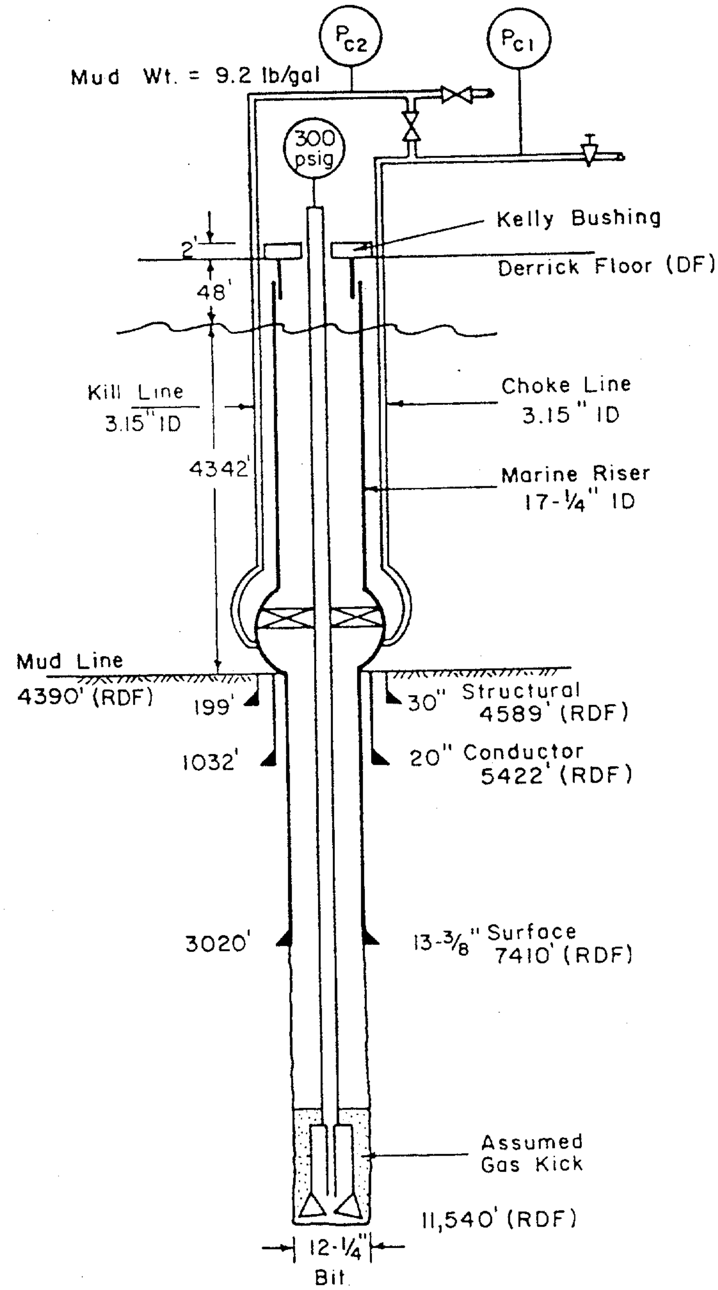


Figure 4 - Schematic Diagram for Congo Well Example

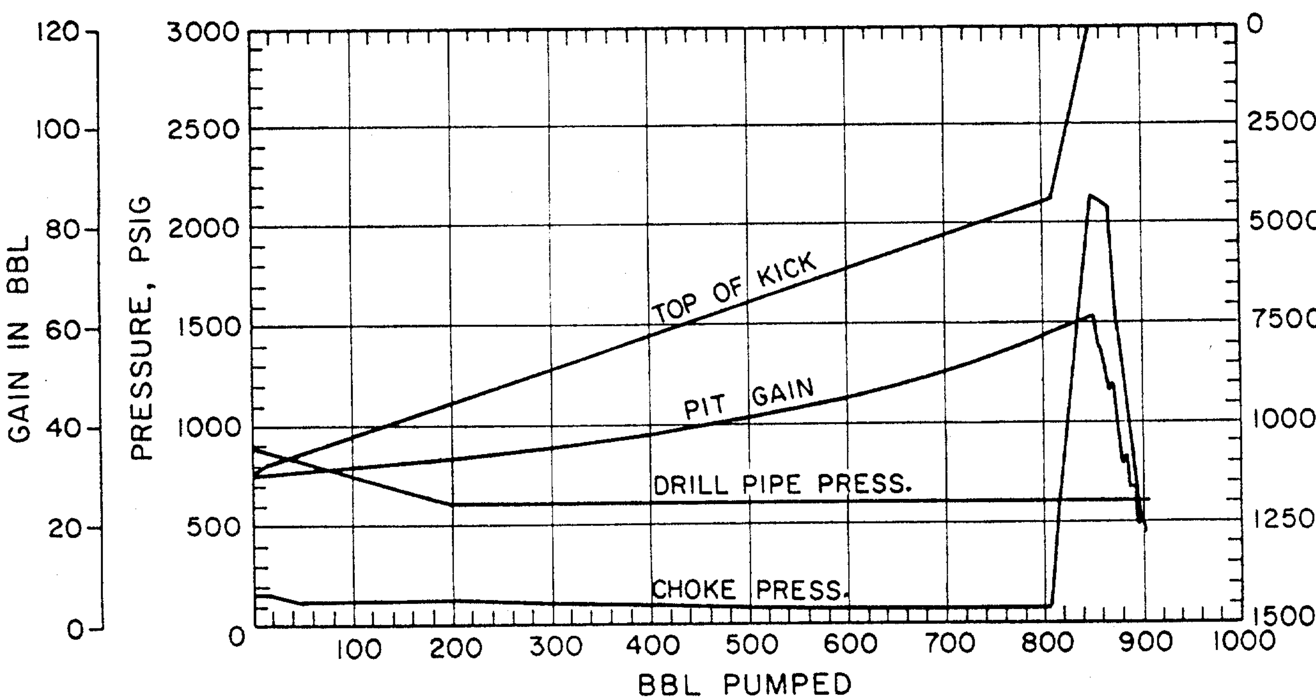


Figure 5 - Predicted Well Behavior for Congo Example

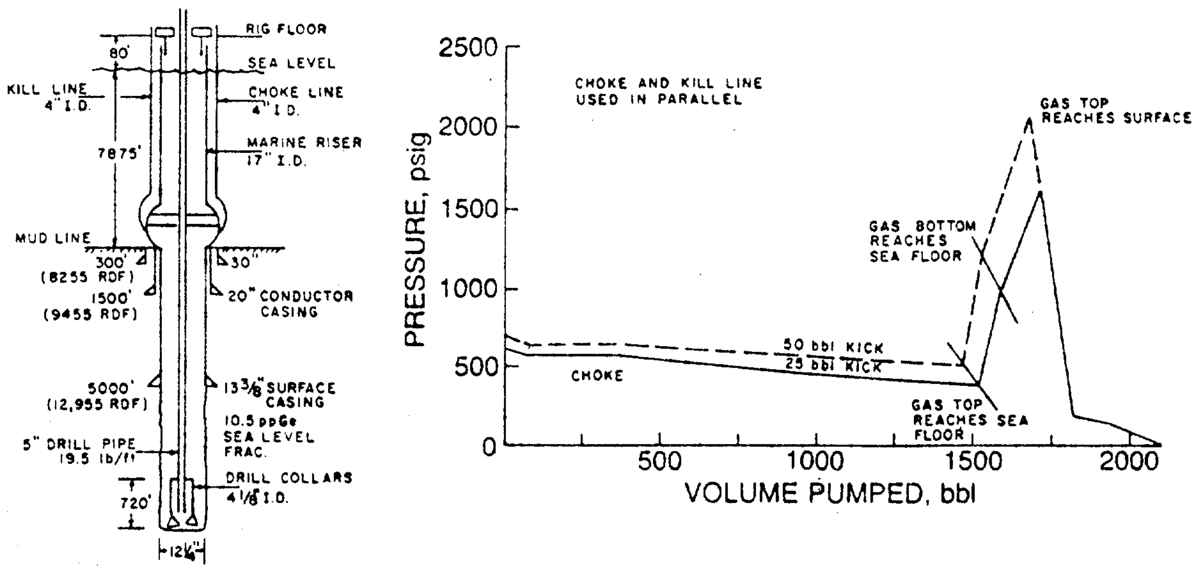


Figure 6 - Predicted Well Behavior for GLOMAR EXPLORER Drillship on Proposed Offshore New Jersey Location.

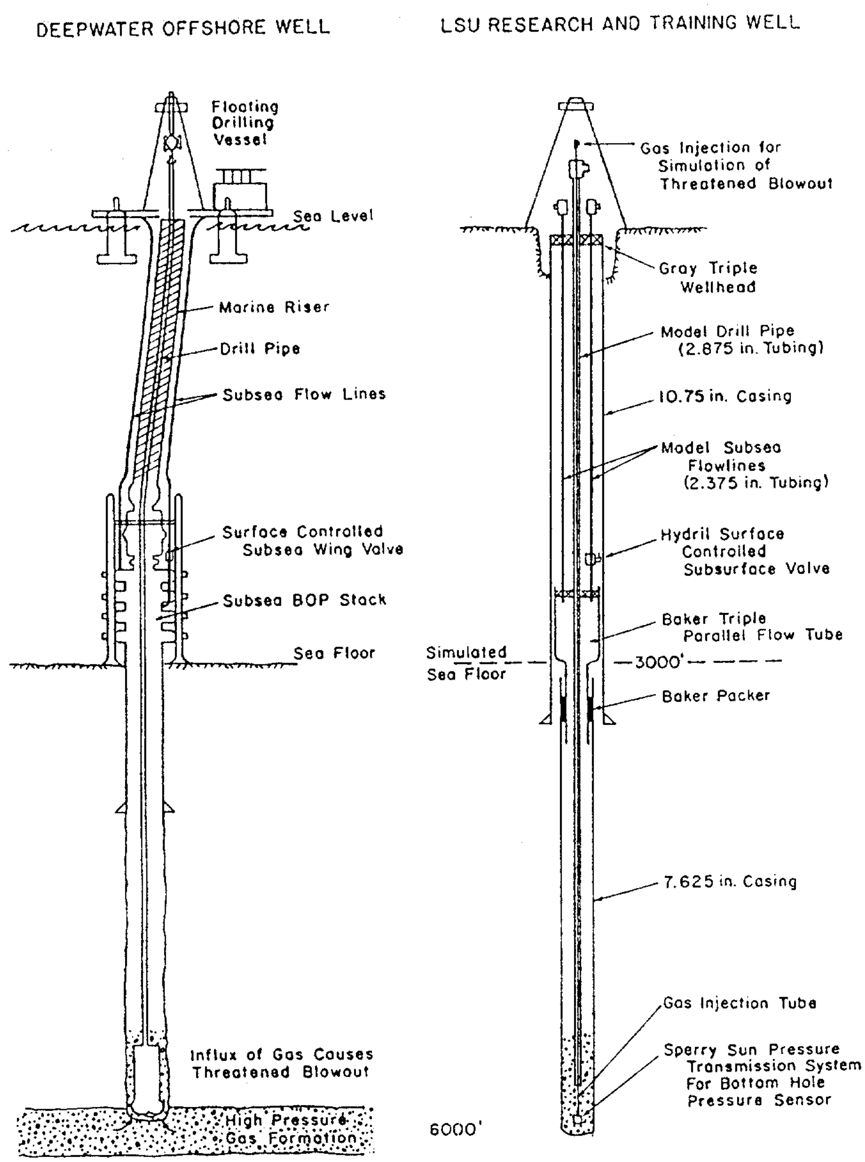


Figure 7 - Well Design Selected to Model Well-Control Operations on a Deepwater Offshore Well.

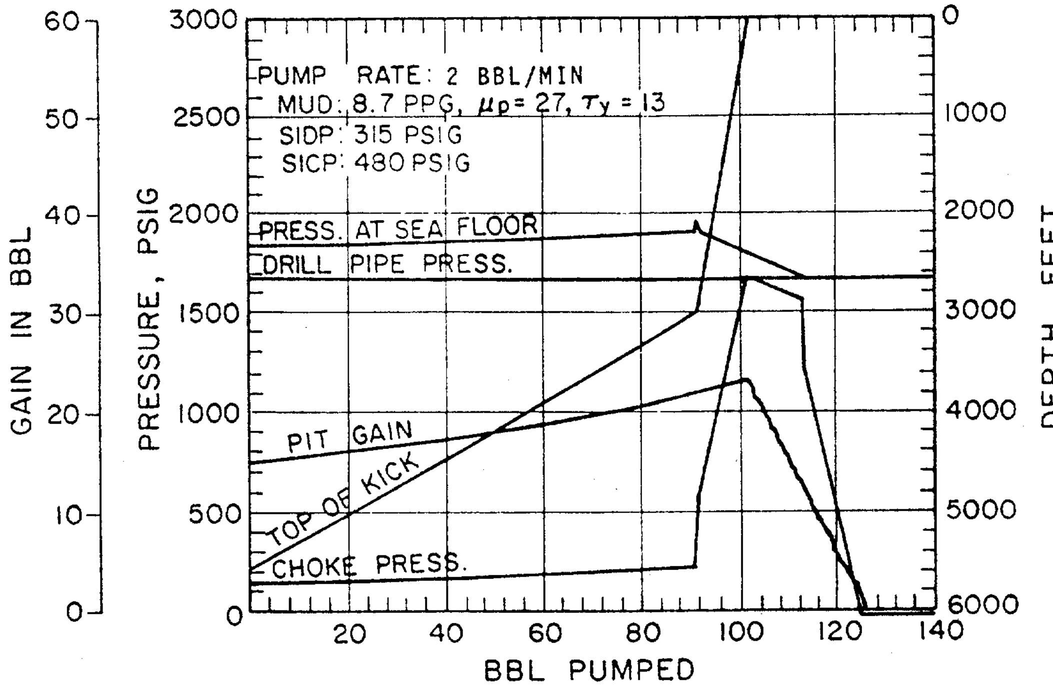


Figure 8 - Predicted Behavior of Experimental Well

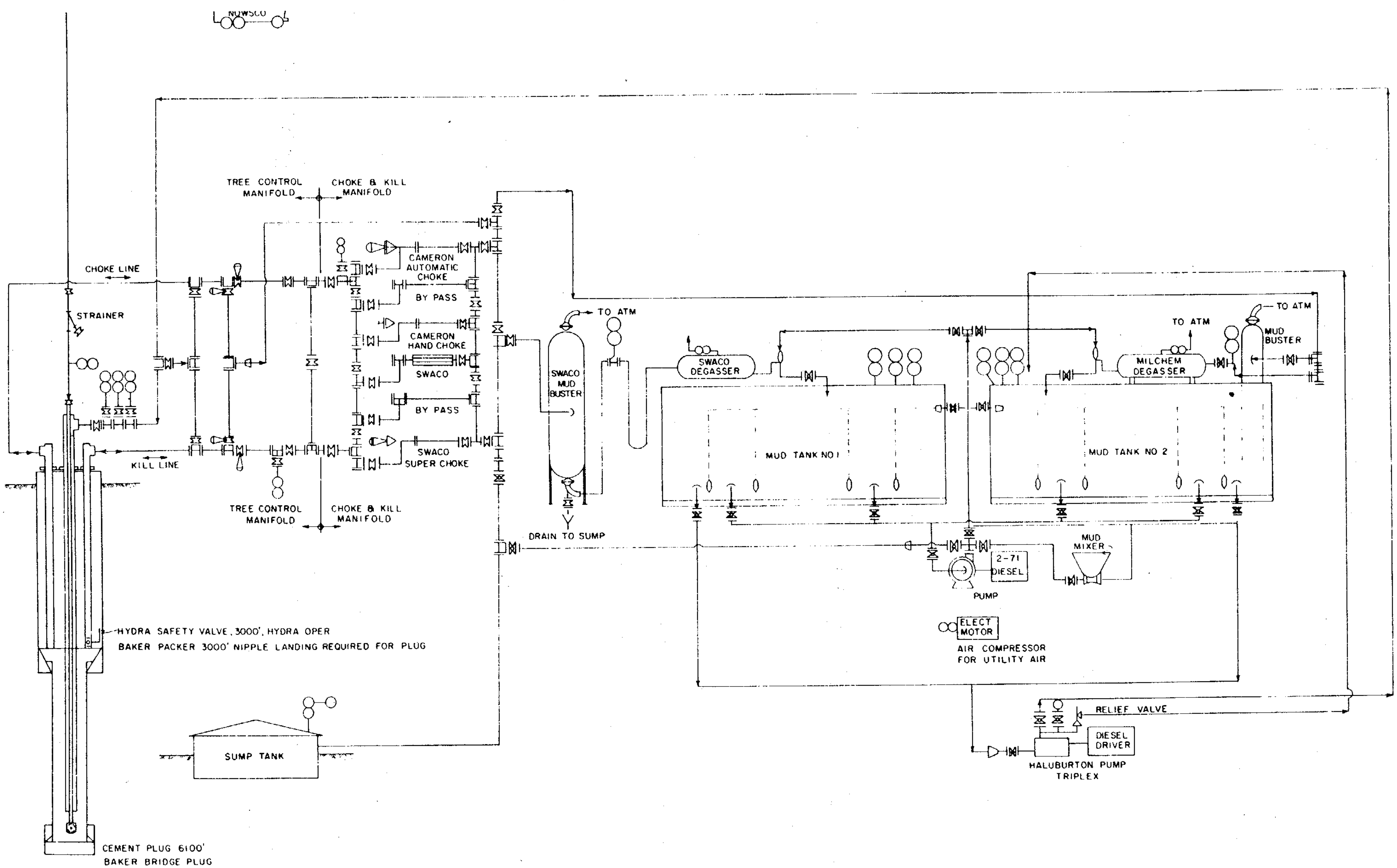


Figure 9 - Schematic Diagram of Associated Surface Equipment for Experimental Well Facility

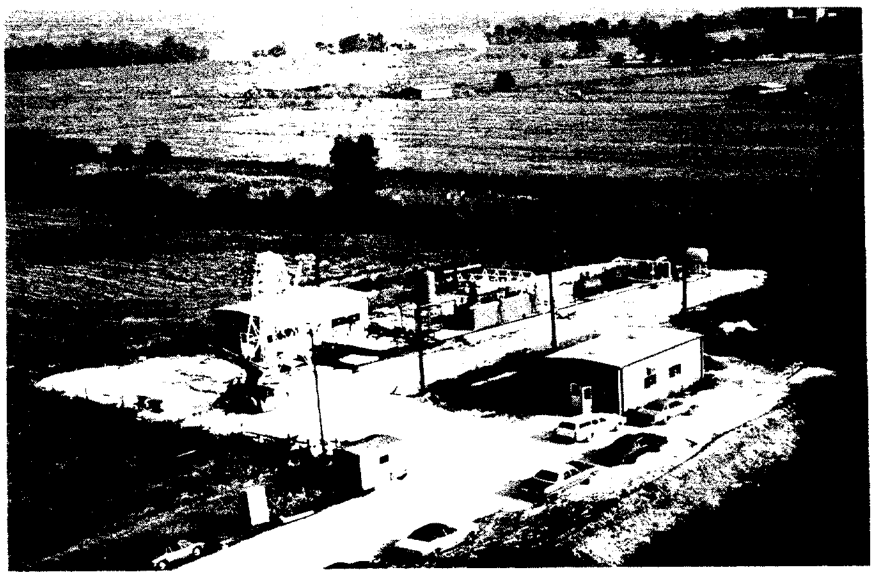
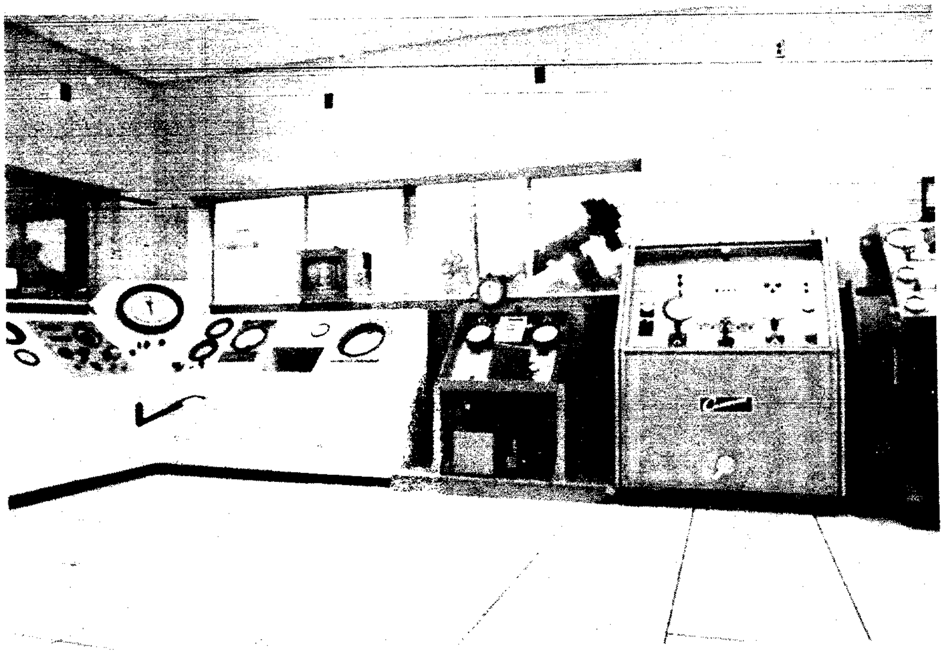


Figure 10 - Aerial Photograph of Experimental Well Facility



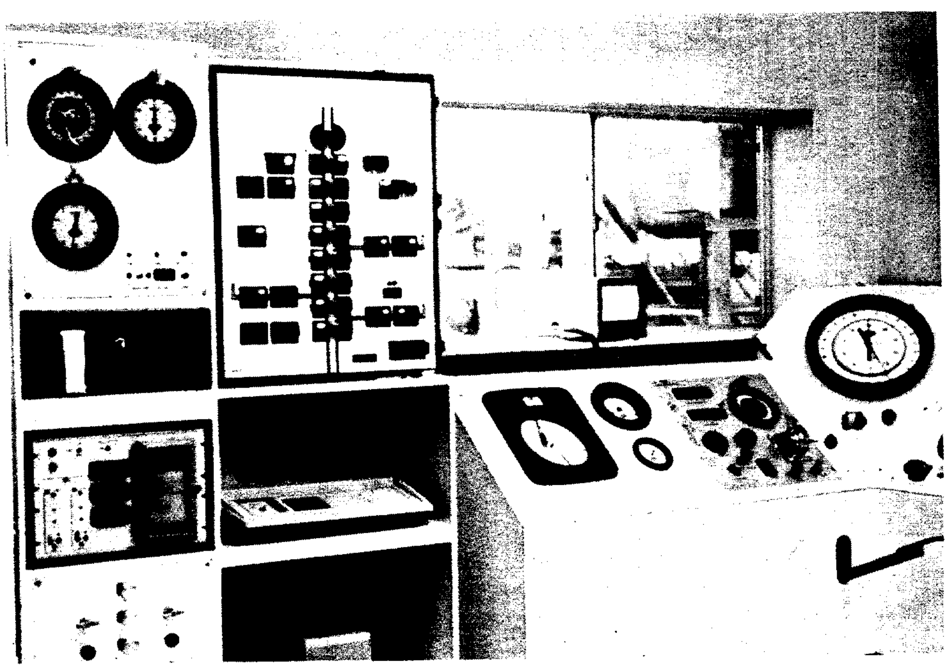


Figure 11 - Instrumentation Panels in Control Room

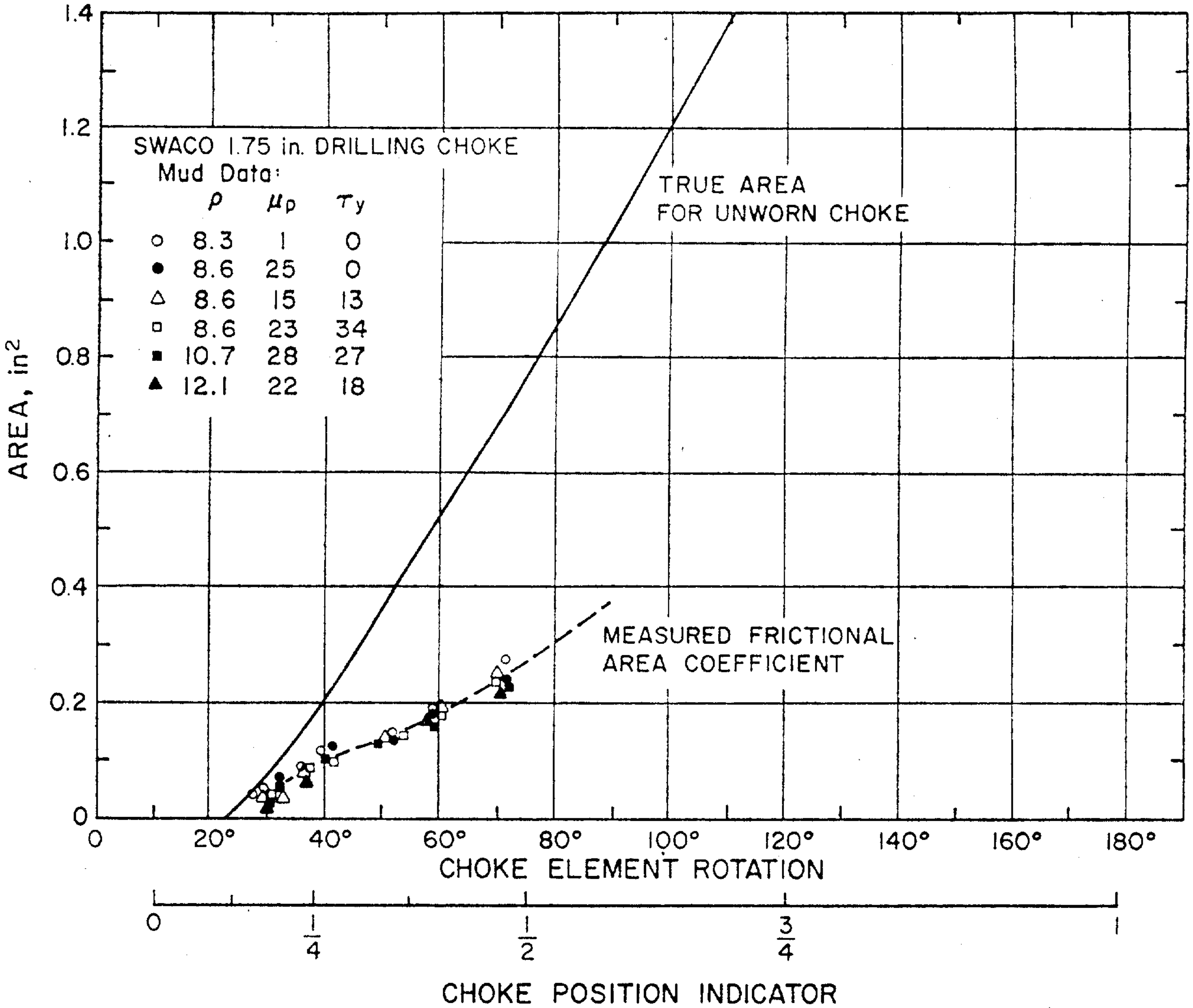


Figure 12 - Measured Frictional Area Coefficients for 1.75 in. Swaco Drilling Choke

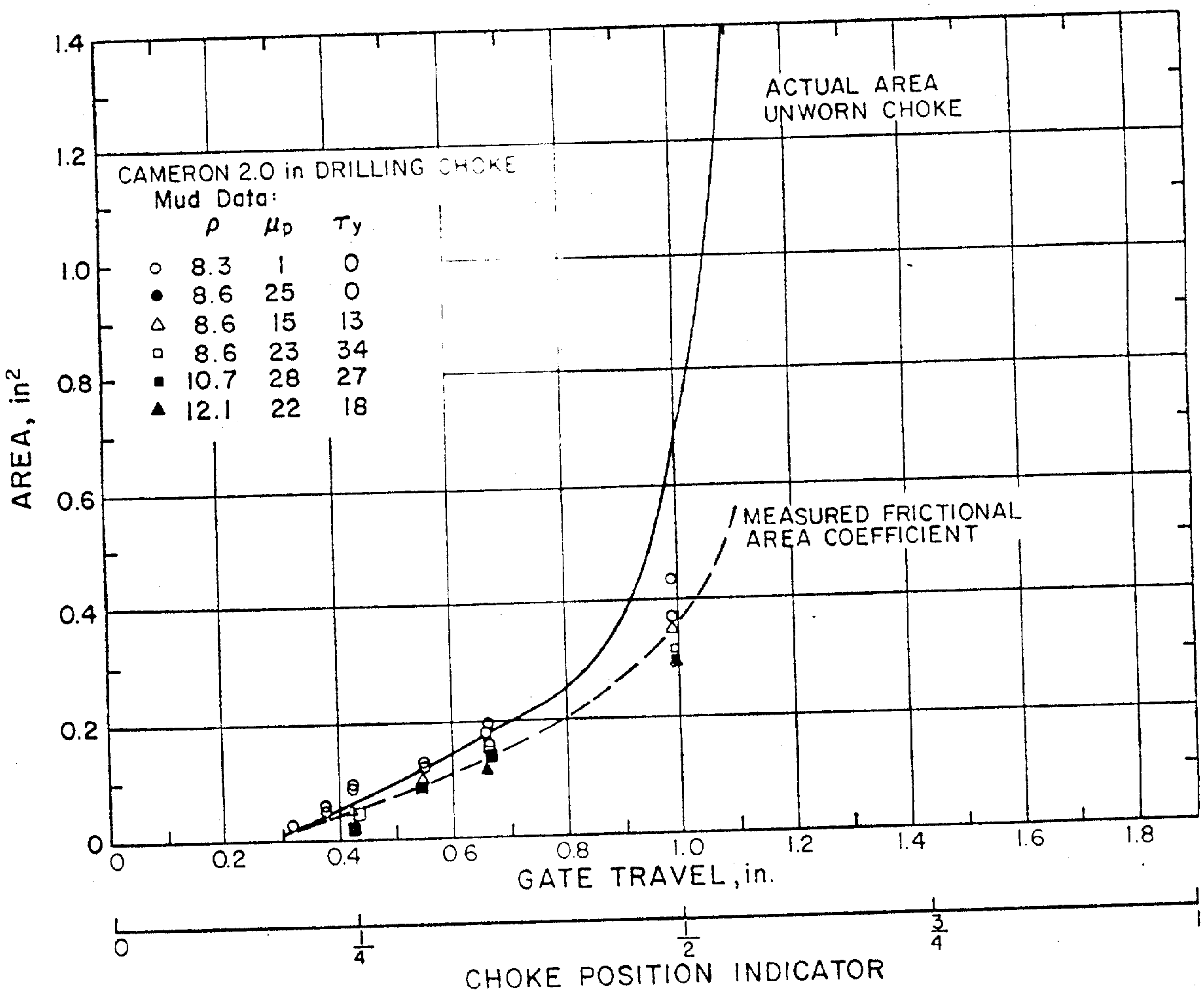
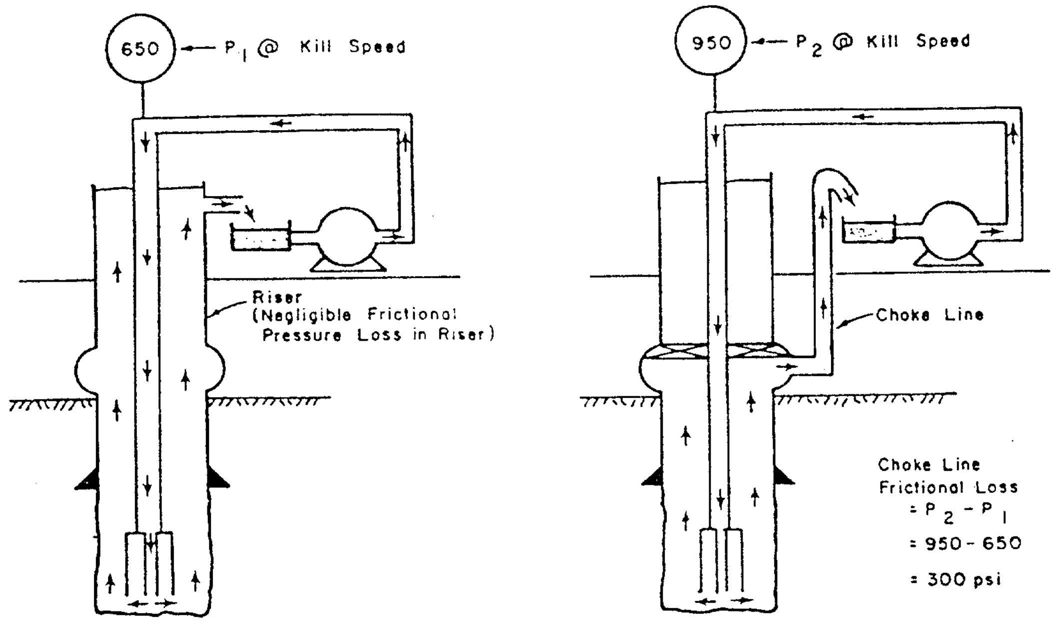
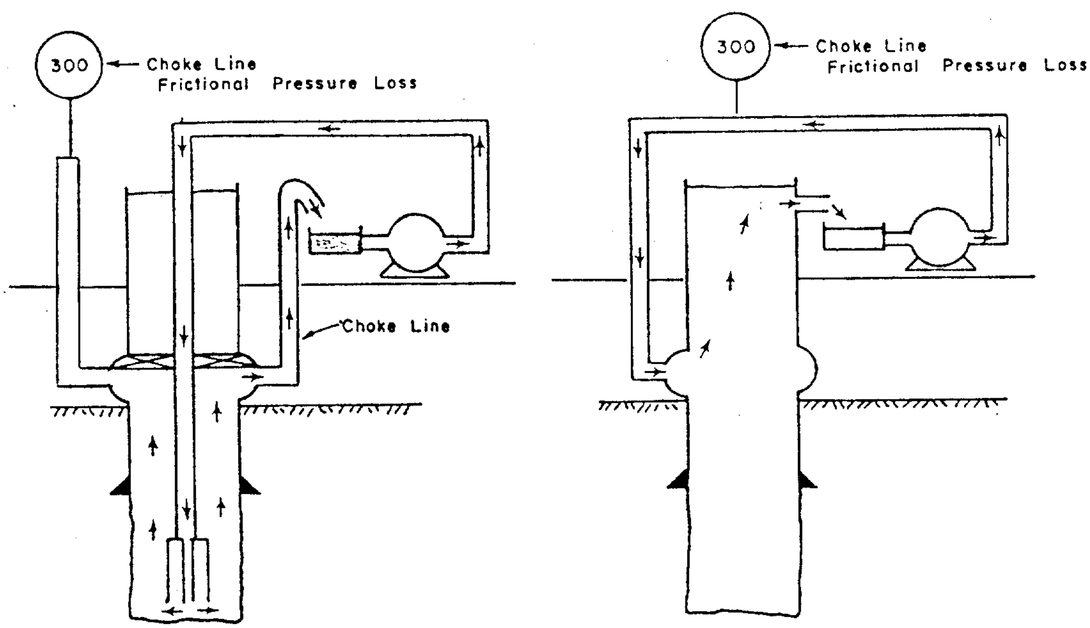


Figure 13 - Measured Frictional Area Coefficients for 2.0 in. Cameron Drilling Choke



(a) MEASUREMENT OF REDUCED PUMP PRESSURE THROUGH MARINE RISER AND THROUGH CHOKE LINE



(b) Use of kill line as monitor line

(c) Reverse circulation down choke line

Figure 14 - Techniques for Measurement of Frictional Pressure Loss in Choke Line

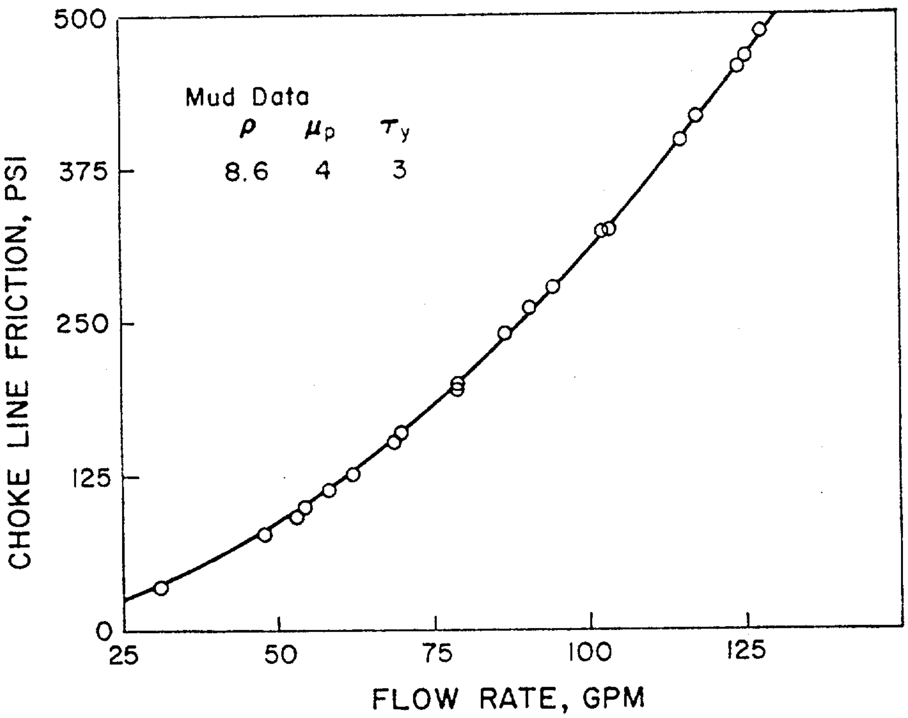
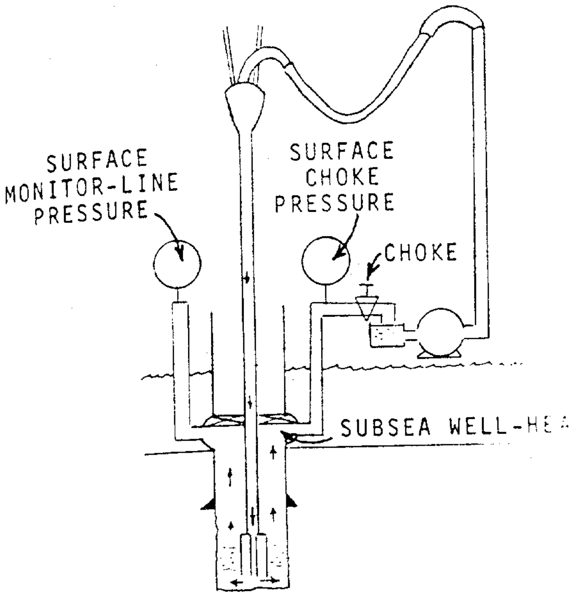


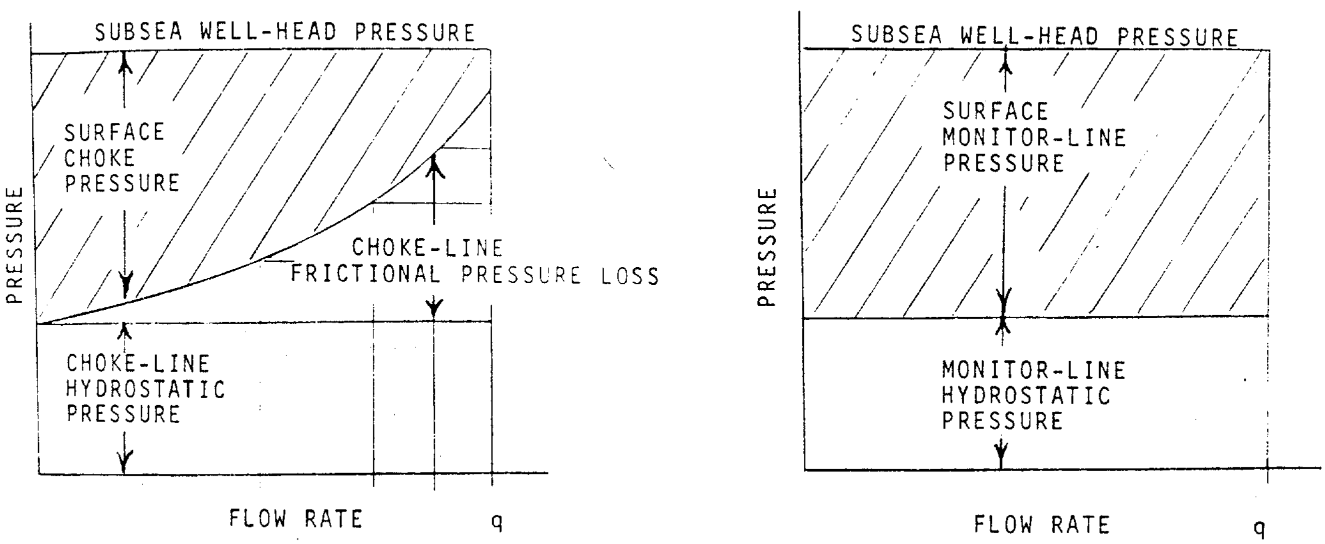
Figure 15 - Comparison of Measured and Calculated Frictional Pressure Losses in a 1.995 in. I.D. Choke Line



NOTE:

SUBSEA WELL-HEAD PRESSURE = SURFACE CHOKE PRESSURE + CHOKE-LINE HYDROSTATIC PRESSURE + CHOKE-LINE FRICTIONAL PRESSURE LOSS

= SURFACE MONITOR-LINE PRESSURE + MONITOR-LINE HYDROSTATIC PRESSURE

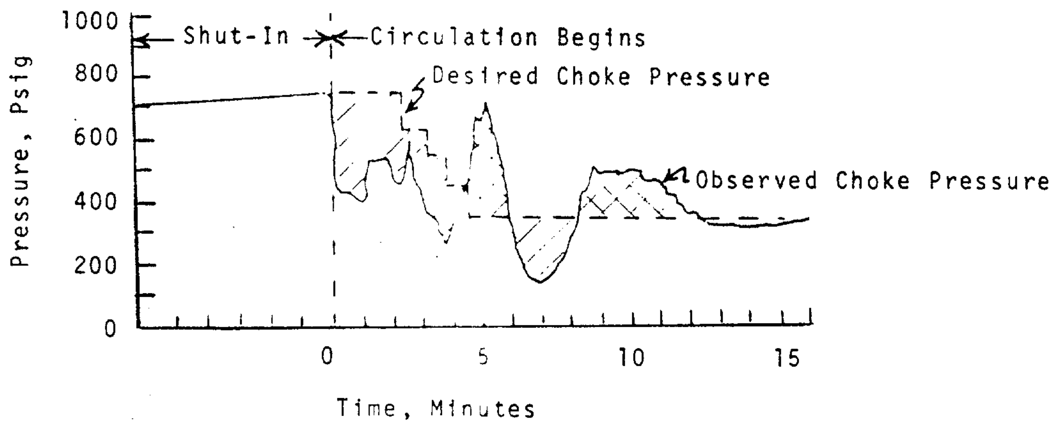


(a) Adjust Choke so that Surface Choke Pressure Decreases by an Amount Equal to the Choke Line Frictional Pressure Loss.

(b) Adjust Choke so that Surface Monitor-Line Pressure Remains Constant at Shut-In Value.

Figure 16 - Proposed Techniques for Pump Start-Up

EXAMPLE 1



EXAMPLE 2

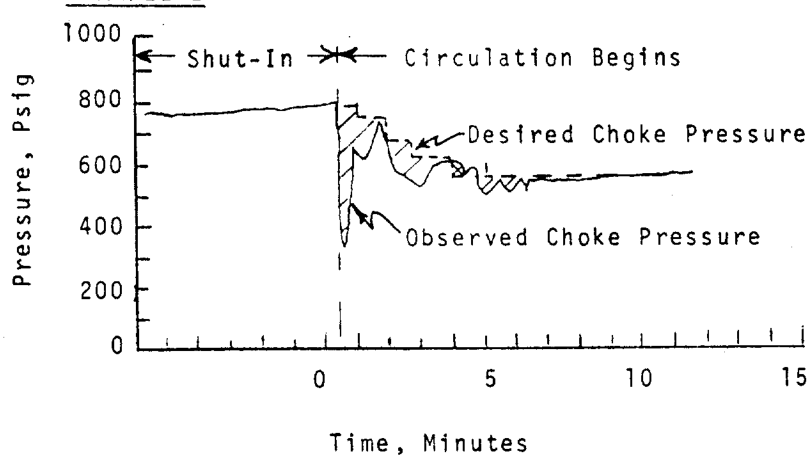


Figure 17 - Typical Choke-Pressure Error Observed During Pump Start-Up

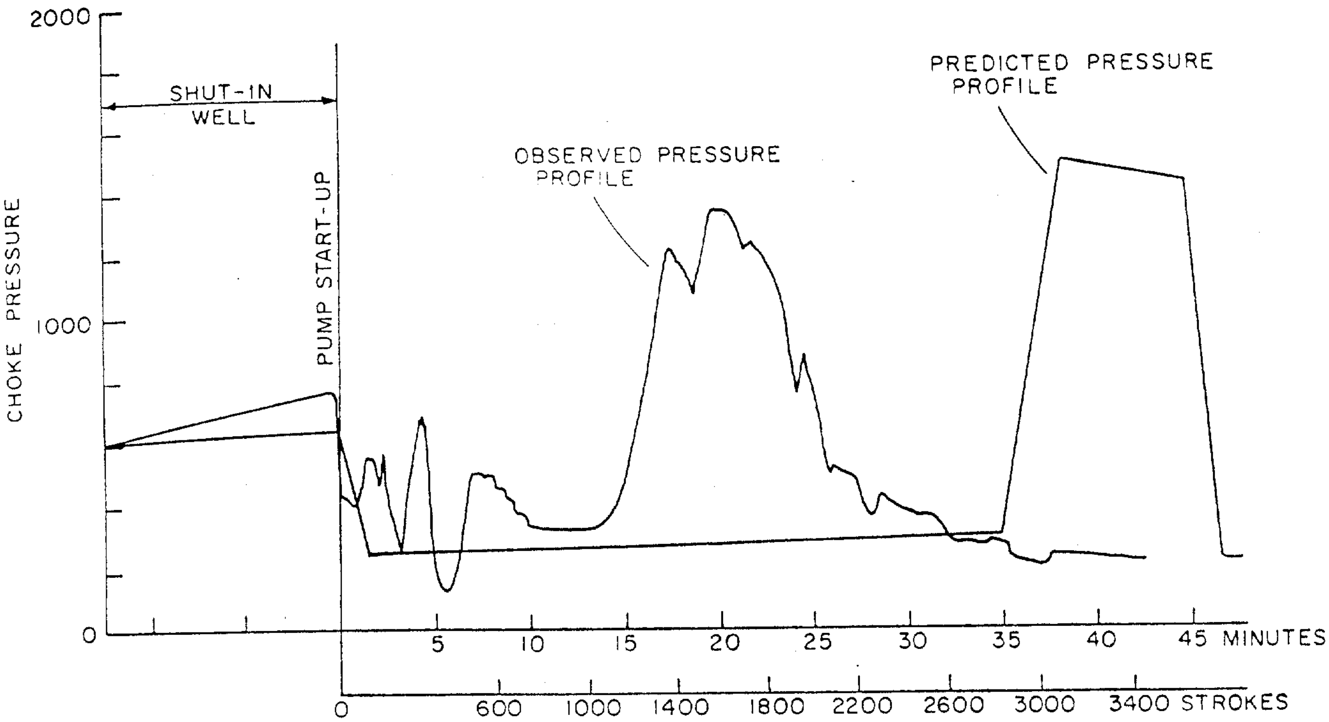
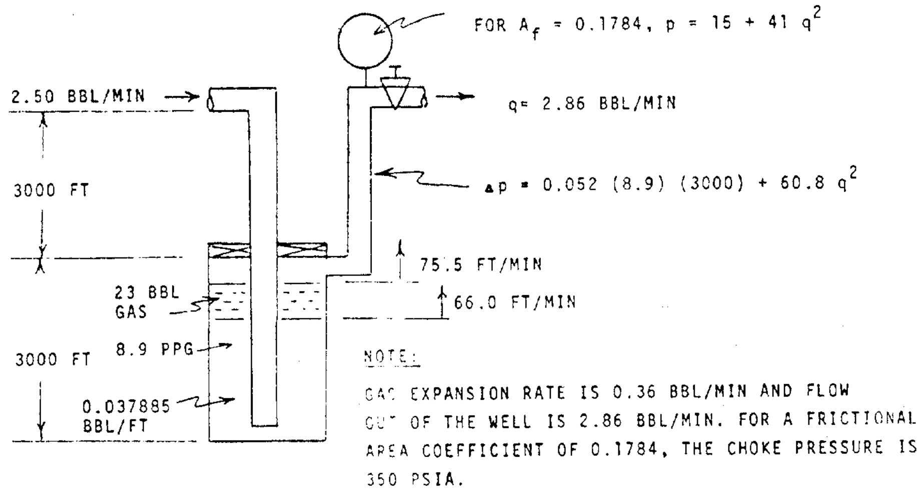
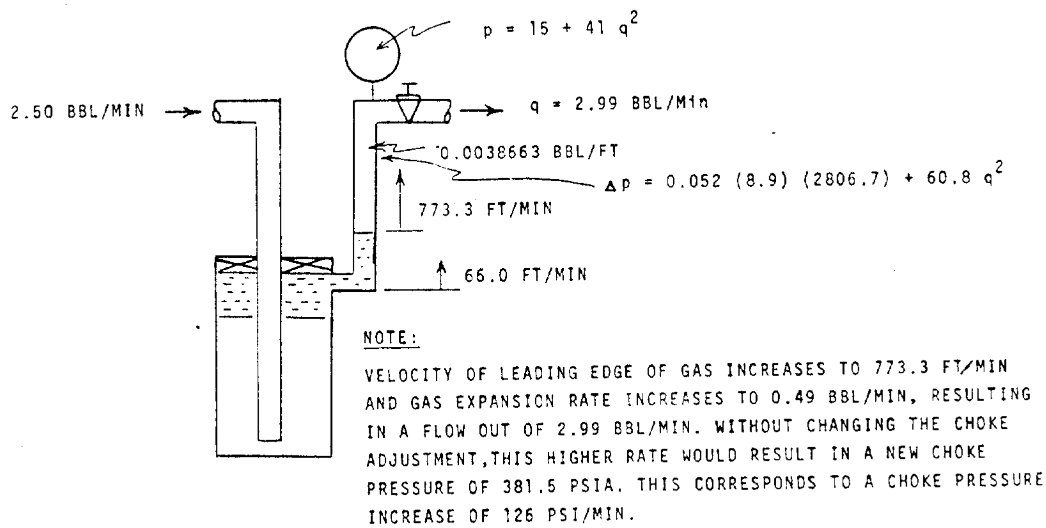


Figure 18 - Comparison of Observed and Predicted Choke Pressure Profile for 20 BBL Gas Kick



(a) WELL CONDITIONS JUST PRIOR TO GAS REACHING THE SEAFLOOR



(b) WELL CONDITIONS FIFTEEN SECONDS AFTER GAS REACHES THE SEAFLOOR

Figure 19 - Computed Natural Choke Pressure Increase When Gas Reaches Seafloor For Well-Control Exercise of Figure 19.

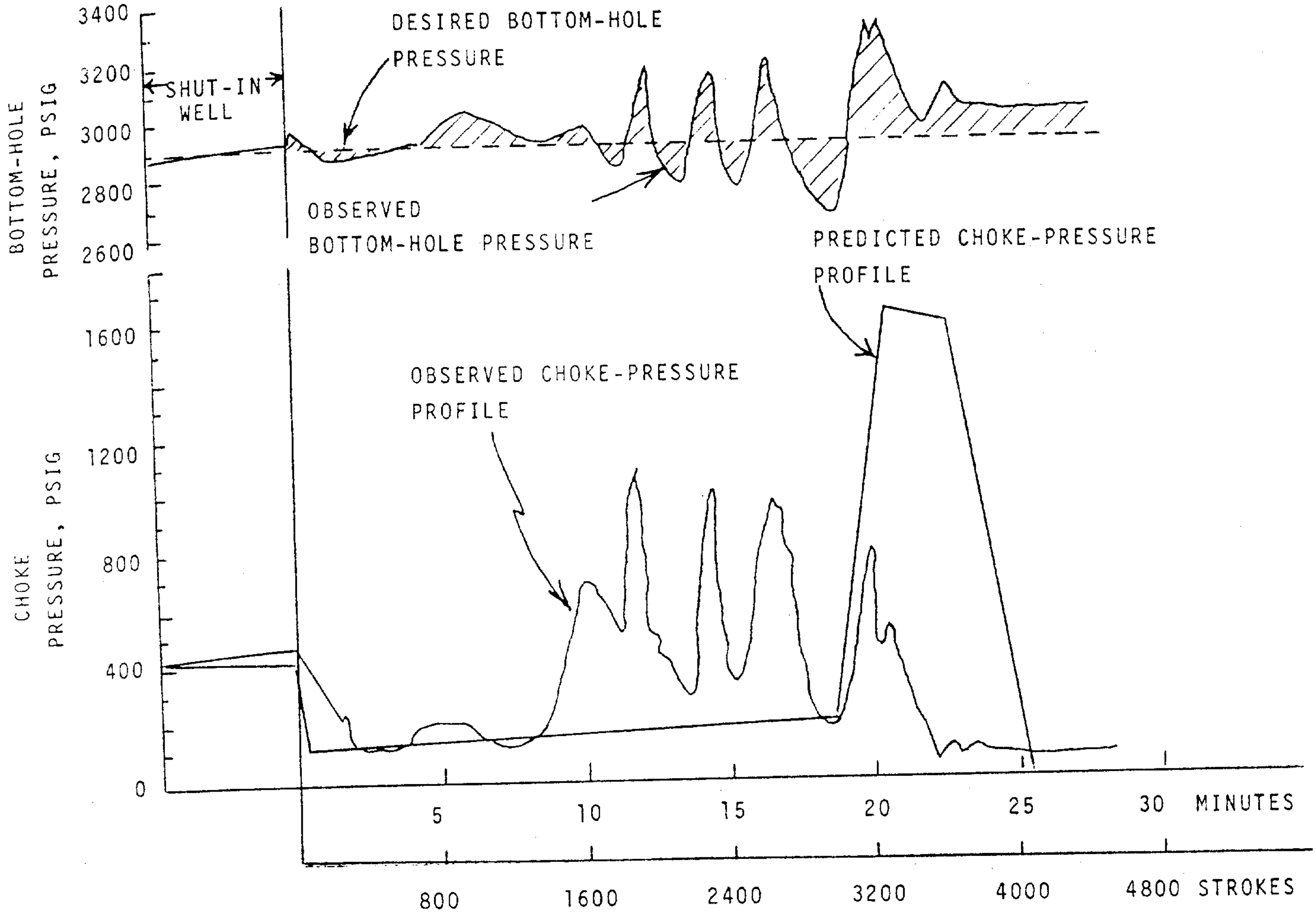


FIGURE 20 - Comparison of Observed and Predicted Choke Pressure Profiles For 15 BBL Gas Kick